EFFECT OF WIND TURBINE GENERATOR MODEL AND SITING ON WIND POWER CHANGES OUT OF LARGE WECS ARRAYS

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ABSTRACT

Previous results have [1,2,3], been concerned with establishing (1) whether operating problems could exist when WECS generation is significant and (2) the proper modification of unit commitment, regulation, and economic dispatch required to provide sufficient system security and alleviate the operating problems caused by WECS generation changes. This paper discusses methods of reducing the WECS generation change through selection of the wind turbine model for each site, selection of an appropriate siting configuration, and wind array controls. An analysis of wind generation change from an echelon and a farm for passage of a thunderstorm is presented to establish the factors concerning the wind turbine model and siting configuration that contribute to these variations. Detailed simulation results indicate more precisely how these factors can be exploited to minimize the WECS generation changes observed. Reduction of the wind generation change over ten minutes is shown to reduce the increase in spinning reserve, unloadable generation and load following requirements on unit commitment when significant WECS generation is present and the farm penetration constraint is satisfied. Controls on the blade pitch angle of all wind turbines in an array or a battery control are shown to reduce both the wind generation change out of an array and the effective farm penetration in anticipation of a storm so that the farm penetration constraint may be satisfied.

1. INTRODUCTION

The research reported in this paper is an extension of previous work [1,2,3]. The objectives of the earlier work was to determine:

(1) if operating problems could exist on automatic generation control (regulation and economic dispatch), frequency regulation, and unit commitment when wind generation capacity is significant;

(2) the penetration limits on wind generation capacity that would alleviate these operating problems.

The results indicated that there were two specific operating problems which could both be eliminated with proper penetration constraints:

(1) The automatic generation control will saturate for long periods when the total change in wind generation for passage of a thunderstorm front and simultaneous load change in a ten minute interval will require non-wind generation change that exceeds load following capability in a ten minute interval. This problem violates NAPSIC performance standards but can be eliminated by imposing a farm penetration constraint on the capacity of all wind turbine generators that can be affected by a single thunderstorm front.

(2) A cycling problem caused by simultaneous load and generation change that induce frequency deviations that exceed governor deadband. This continual cycling of steam turbine units is objectionable to generator operators and can cause increased maintainance costs, forced outage rates and ultimately reduce unit life. The cycling of nuclear units is of concern for safety reasons in addition to those mentioned above. The cycling problem can occur due to a storm front sweeping through a wind generator array causing large power variations on successive echelons. A echelon penetration constraint on the capacity of all WTGs that can experience simultaneous change in generation level will eliminate this cycling problem.

A subsequent study [3] was devoted to a detailed discussion of the modification of unit commitment, regulation, and economic dispatch when WECS generation is significant. A modified farm penetration constraint is determined that limits WECS generation to be less than the maximum first contingency loss of resource or commitment. A violation of this farm penetration constraint is shown to necessarily cause an increase in the maximum first contingency loss of resource or commitment to the level of the farm capacity and thus an increase in load following, spinning reserve, and unloadable generation requirements on unit commitment. A discussion of the methodology, costs and benefits of changing unit commitment, when WECS generation is significant and the farm penetration constraint is or is not violated, is included. A discussion of the methods for modifying unit commitment is also included. Detailed simulation results that document the reduction of the effects of significant WECS generation change through the modification of the unit commitment regulation, and economic dispatch is also presented.

A modified echelon penetration constraint is proposed which limits instantaneous change and rate of change of wind array generation that must be handled by frequency regulation and regulation controls. This constraint is imposed to limit cycling of units.

This paper presents both analysis and simulation results that show how to decrease the WECS generation change over a ten minute interval through selection of the wind turbine generator model at each site, the siting configuration, and controls on the power variation out of the array. These direct controls of power out of the array are shown to also permit reduction of the effective farm penetration below the farm penetration constraint level and thus make the increase in spinning reserve, unloadable generation, and load following requirement depend on the probable change in WECS generation over a ten minute interval rather than on the farm capacity, which would be the maximum first contingency loss of resource or commitment for a particular utility if the farm penetration constraint were violated.

2. ANALYSIS AND SIMULATION OF WIND GENERATION CHANGE FROM AN ECHELON AND A FARM

The purpose of this section is to:

(1) briefly describe the model and simulation of wind power change from an array of wind turbine generators for passage of a thunderstorm front;

(2) analyze the power change and rate of change from an echelon and a farm in terms of the factors that determine these changes;

(3) review the methodology for determining spinning reserve, unloadable generation, and load following requirements on unit commitment and briefly discuss how the selection of wind turbine models, siting configuration and wind array controls can influence these requirements.

A model of a single MOD-1 WTG and an array of wind turbine generators is developed. The MOD-1 WTG model, given in [1], is a static nonlinear model that relates generation to wind speed if the wind speed does not exceed the cut out velocity for a sustained period which causes shutdown to avoid damage. The dynamics of the shutdown startup sequence is also modeled since a thunderstorm can cause such a shutdown. A similar model of a MOD-2 wind turbine is discussed in section 3 of this paper in order to compare the changes from an identical siting configuration of MOD-1 and MOD-2 wind turbines experiencing the identical wind speed profile.

The farm model, which is common for every wind turbine model, assumes the motion of thunderstorm front is normal to each echelon. The power out of the first echelon is then just the generation out of a single generator in this echelon multiplied by the number of generators in this echelon. The generation out of the j^{th} echelon is the generation profile of this WTG in the first echelon (1) delayed by an interval (d_j/V_o) proportional to the distance between the first and j^{th} echelon and inversely proportional to the speed of the thunderstorm front, and (2) multiplied by the number of WTGs in the j^{th} echelon. The generation out of all echelons is simply summed to obtain the generation time profile for the farm for passage of a thunderstorm front.

The worst case change and rate of change from a coastal farm will now be determined. The results are derived based initially on simulation of a worst case coastal farm experiencing a worst case thunderstorm wind speed versus time profile.

The worst case MOD-1 siting configuration for a coastal farm [1], which is a farm located on the coast of a body of water, shows a 0.5 mi. spacing between 50 generators in each echelon and a 2 mi. separation between two echelons. The echelons are assumed sited normal to the motion of the thunderstorm front.

The wind speed profile of a worst case thunderstorm gust front on the WTGs in the first echelon is shown in Figure 1A. The initial wind speed increase is due to the leading edge outflow and the second segment of high wind speed is due to the trailing edge inflow. The wind speed increases from 13 km/hr. at t = 0 to 26. km/hr. at t = 50 causing the power on each WTG in the first echelon to increase from zero to capacity (1.5 MW) in that interval. The power remains at capacity for speeds in excess of 26 km/hr. due to blade pitch controls. The thunderstorm front was chosen with a 13 km/hr. initial wind speed to cause maximum power variations out of any WTG.

The power variation out of the coastal wind farm of MOD-1 WTGs, shown in Figure 1B, shows two 75 megawatt ramps each 50 seconds long which are the increases in generation due to the leading edge outflow passing over the two echelons. The two pronounced power decreases are due to the shutdown of WTGs on both echelons caused by sustained wind speed exceeding cutout velocity. The time interval between the successive increases or decreases on the two echelons is 240 seconds.

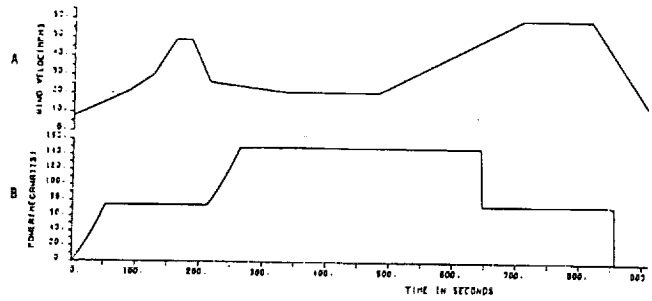

Figure 1 Simulation of Coastal Farm for a Thunderstorm Front

The logic for initiation of shutdown of a WTG requires the output of a one minute smoothed wind speed $W_{av}(k)$, to exceed 64 km/hr. Thus, a shutdown only occurs for the trailing edge inflow because the excessive wind speed for the leading edge outflow is not sustained long enough to trigger a shutdown.

The power out of any MOD-1 WTG does not decrease after the first 50 seconds of the leading edge outflow passes over (until the shutdown) due to the blade pitch control that maintains constant maximum generation over a wide range of wind velocities (26 km/hr. - 64 km/hr.).

An analysis of power variations out of an echelon and a farm is now performed to determine the factors that influence power increases and decreases for passage of a thunderstorm front. The analysis assumed all WTGs in a farm are similar, and arranged in straight parallel lines normal to the motion of the front. The analysis is not restricted to any particular WTG model if the parameter D is interpreted as the distance between the leading edge of the thunderstorm and the point where the wind speed reaches V_R, the wind speed at which that WTG model achieves rated generation. This maximum change and rate of change in generation is derived based on the additional assumption that the wind speed is below V_{ci}, the cut in velocity for the WTG before the front arrives.

The time in seconds for a particular WTG to change its generation from zero to capacity C_W for a thunderstorm front is

$$T_M = 3600\ D/V_o \text{ sec} \qquad (1)$$

where V_o is the velocity of the front and D is the distance from the very leading edge of the front to the point internal to the front at which wind speed first reaches V_R, the wind speed level just sufficient for maximum generation on that WTG model (C_W). Thus a thunderstorm front with a minimum value of T_M due to a minimum value of D and a maximum value of V_o,

would require a higher response rate for the governor frequency regulation and AGC regulation controls to handle this change in wind power generation without excessive or sustained change in frequency or area control error.

The time interval T_e between initiation of generation changes on two adjacent echelons is

$$T_e = \frac{3600\ d}{V_o} \text{ sec} \tag{2}$$

where d is the distance between echelons in miles. The distance d must be greater than D for the response of two adjacent echelons due to passage of the leading edge outflow not to overlap. The shorter T_e and d, the higher the response rate capability of the power system required to handle this generation change without excessive or sustained frequency or area control error changes.

The maximum change of generation from an echelon of N_e WTGs with rated capacity C_W is

$$\Delta P_e = N_e \times C_W$$

and the maximum average rate of change during period T_M required for passage of the leading edge outflow is

$$\frac{\Delta P_e^+}{\Delta t} = \frac{N_e \times C_W}{T_M} \tag{3}$$

The maximum average rate of change of power from an echelon during the period T_S required for shutdown during the passage of the trailing edge inflow of a thunderstorm front is

$$\frac{\Delta P_e^-}{\Delta t} = \frac{N_e \times C_W}{T_S} \tag{4}$$

The maximum power change out of a farm composed of N_f WTGs for passage of either the leading edge outflow or trailing edge inflow is

$$\Delta P_f = N_f \times C_W \tag{5}$$

The maximum average rate of change from the farm during the period $(N_f/N_e - 1)\ T_e + T_M$ required for the increase in generation during the passage of the leading edge outlfow is

$$\frac{\Delta P_f^-}{\Delta t} = \frac{N_f \times C_W}{\left(\frac{N_f}{N_e} - 1\right) T_e + T_M} \tag{6}$$

The maximum average rate of change from the farm during the period $(N_f/N_e - 1)\ T_e + T_S$ required for shutdown of all the echelons during passage of the trailing edge inflow of the thunderstorm front is

$$\frac{\Delta P_f}{\Delta t} = \frac{N_f \times C_W}{\left(\frac{N_f}{N_e} - 1\right) T_e + T_S} \tag{7}$$

The formulas for WECS generation change out of an echelon and farm for passage of the leading edge outflow are given by equations (3) and (6) where T_M and T_e satisfy equations (1) and (2) respectively. Results obtained in section 4, where generators in echelons are randomly sited in a strip D miles long rather than in straight lines normal to the motion of the front, indicated that the rate of change of WECS generation in an echelon for passage of a thunderstorm trailing edge inflow to be identical to that for the passage of the thunderstorm's leading edge outflow. Thus, the formulas for rate of change of power from an echelon (3) or a farm (6) are appropriate for passage of both the leading edge outflow or trailing edge inflow if the siting configuration is not in straight lines normal to the motion of the front which will generally be true.

These formulas will not be used to derive detailed expressions that indicate more precisely the factors that contribute to $\frac{dP_e}{dt}$ and $\frac{dP_f}{dt}$ so that the model WTG and siting configuration can be selected to keep these WECS power generation rates below that of the power system average response rate capability.

The power rate of change out of an echelon is quite different depending on whether the density of wind turbines in an array is or is not uniform; i.e., whether the density of wind turbine in an echelon, defined

$$\rho_E = \frac{N_e}{D \times D_o} \tag{8}$$

is or is not identical to the density in the farm

$$\rho_f = \frac{N_f}{(V_o T + D)\ D_o} \qquad T = \left(\frac{N_f}{N_e} - 1\right) T_e \tag{9}$$

where T is the time for the thunderstorm to move through the farm. The formula for power rate of change from an echelon (3) becomes upon substitution of (2) and (9)

$$\frac{dP_e}{dt} = \frac{\rho_f\ D_o\ V_o\ C_W}{3600} \tag{10}$$

if $\rho_f = \rho_e$ as it is more nearly in a low density midwestern farm siting configuration. Note that V_o and D_o are the velocity of the thunderstorm front and the width of the front respectively, C_W is the capacity in MW for the wind turbine model, and ρ_f is the uniform density of wind turbine in the farm in #/mi.^{2} The rate of change of power out of an echelon is

$$\frac{dP_e}{dt} = \frac{\rho_e\ D_o\ V_o}{3600} \left(D\left[\frac{V_R - V_{CI}}{D}\right]\left[\frac{C_W}{V_R - V_{CI}}\right]\right) \tag{11}$$

if $\rho_e > \rho_f$, as in the coastal farm siting configuration. Note that in this case $\frac{dP_e}{dt}$ depend on

$\frac{C_W}{V_R - V_{CI}}$ - The slope of the power versus wind speed curve for a wind turbine model for the range of velocities $V_R - V_{CI}$ where power can change.

$\frac{V_R - V_{CI}}{D}$ - The slope of the wind speed profile of thunderstorm front for the distance D into the front.

D - The distance into a particular thunderstorm front where power will change on the WTG model considered or alternately the length of an echelon in the direction of motion of the thunderstorm front.

The formula for power out of a farm (6) has the form

$$\frac{dP_f}{dt} = \frac{\rho_f D_o V_o C_W}{3600} \tag{12}$$

upon subsititution (1,2, 9) into (6). Note when the density of an echelon is the same as that of the farm, the rate of change out of an echelon is the same as that out of the farm.

It is clear that the wind generation rates of change from an echelon (10,11) and farm (12) depend on the width (D_o), speed (V_o), and the slope $\frac{V_R - V_{CI}}{D}$ of the leading edge outflow for the thunderstorm front. The remaining parameters depend either on the WTG model (C_W, $\frac{C_W}{V_R - V_{CI}}$, D) or on the siting configuration (ρ_f, ρ_e, d). The effects of different WTG models and siting configuration characteristics on the change and rates of change from an echelon and a farm for different wind speed profiles will be demonstrated in the next two sections of the paper. The purpose of studying the effects of WTG models and siting configuration patterns is to analyze how such factors can be used to minimize WECS generation change and thus minimize any increase in load following, spinning reserve and unloadable generation requirements provided through unit commitment modification when WECS generation is present. These increased requirements add to fuel, operating, and maintainance costs but are required to maintain system security as discussed in [3]. Changes in regulation and economic dispatch (load following) controls must also be implemented [3] to take advantage of the increased response and response rate capability provided by the increased spinning reserve, unloadable generation, and load following capability, when WECS generation is present. Thus minimizing WECS generation change by WTG model and siting configuration selection can either dramatically decrease or possibly eliminate the need for modifying the unit commitment, regulation, and economic dispatch when WECS generation is present.

A brief discussion of spinning reserve, unloadable generation, and load following requirements and how they are affected by the magnitudes of the change and rate of change from an echelon and a farm is now presented. The two factors that determine the spinning reserve, unloadable generation, and load following requirements are the maximum probable rise ΔL_k^+ and drop ΔL_k^- in thermal load in ten minutes. These maximum probable changes are defined as

$$\Delta L_k^+ = \max\{(L_{k+1} - L_k)T + D_R + Q_{Wk}^+ + Q_{Lk}^+, 0\}$$
$$\Delta L_k^- = \max\{-(L_{k+1} - L_k)T + D_C + Q_{Wk}^- + W_{Lk}^-, 0\} \tag{13}$$

where

L_k - thermal load at the k hour

$(L_{k+1} - L_k)T$ - predicted change in thermal load in ten minutes

T = .1667 hour = ten minutes

Q_{Wk}^+ Maximum probable drop in WECS generation output in 10 minutes

Q_{Wk}^- Maximum probable rise in WECS generation output in 10 minutes

Q_{Lk}^+ Maximum probable rise in system load in 10 minutes

Q_{Lk}^- Maximum probable drop in system load in 10 minutes

D_R Largest single resource (generation or import) subject to failure

D_C Largest single commitment (export) subject to failure

The spinning reserve SR_k, unloadable generation SS_k, and load following capabilities LF_k for a unit commitment where

G_k Required load-following capacity

f Average minimum generation level of load-following units as a fraction of maximum capacity

g_k Average operating level of load-following units above level $f (0 \leq g_k \leq 1 - f)$

r Average ramp rate of load-following units in % of rated capacity per minute

are defined as

$$SR_k = (1 - f - g_k)\, G_k$$
$$SS_k = g_k\, G_k \tag{14}$$
$$LF_k = 10r\, G_k$$

when there is no unconnected hydro or pumped storage units, interruptible load, and unused but connected base loaded generation to contribute to spinning reserve and unloadable generation capability. The requirements for security on the system are that

$$SR_k = (1 - f - g_k)\, G_k \geq \Delta L_k^+ \tag{15}$$

$$SS_k = g_k\, G_k \geq \Delta L_k^- \tag{16}$$

$$LF_k = 10r\, G_k \geq \max\{\Delta L_k^+, \Delta L_k^-\} \tag{17}$$

The presence of significant wind generation can affect the maximum first contingency loss of resource D_R and commitment D_C and the probable rise Q_{Wk}^- and drop Q_{Wk}^+ in wind generation in ten minutes. The farm penetration constraint [3] limits the maximum change in wind generation in an array for passage of a thunderstorm to be less than the minimum of the maximum first contingency loss of resource or commitment

$$N_F\, C_W \leq \min(D_R, D_C) \tag{18}$$

where C_W is the capacity of each of the N_f wind turbines in the farm. If the farm penetration constraint is violated in some region due to favorable economics and limited siting availability due to wind, environmental or other factors, then either D_R or D_C or both must be increased to the farm capacity and $Q^+_{Wk} = Q^-_{Wk} = 0$. The logic for changing D_R, D_C or both is that the maximum first contingecny loss of resource or commitment is now the worst case changes in wind generation due to passage of the thunderstorm's trailing edge inflow and leading edge outflow respectively as indicated by the simulation results given earlier in this section. Q^+_{Wk} and Q^-_{Wk} are set to zero because the effect of wind generation has been already included in adjustment of D_R and D_C and thus ΔL^+_k and ΔL^-_k.

If the farm penetration constraint is not violated, D_R and D_C are not changed and values of Q^+_{Wk} and Q^-_{Wk} must be determined. These probable or predicted changes in wind generation (Q^+_{Wk}, Q^-_{Wk}) depend on the anticipated wind conditions, the wind turbine models in the array, the siting of wind turbines, and the correlation of wind speeds at the various sites. These factors and their effect on the probable change in WECS generation in ten minutes will be discussed in the next two sections.

Two methods for determining or setting Q^+_{Wk}, Q^-_{Wk} were discussed in [3]. The first method is based on reliability analysis that includes the statistics of WECS generation change on a particular array for anticipated wind conditions and can select ΔL^-_k in addition to ΔL^+_k. A second method would select Q^+_{Wk} and Q^-_{Wk} based on a weighted prediction of change of WECS generation change on a specific array and anticipated wind conditions. The weighting would depend on the operating procedure of the utility.

The proper selection of wind turbine models and the siting configuration can dramatically reduce Q^+_{Wk} and Q^-_{Wk} when the farm penetration constraint is satisfied. Thus the analysis of how the factors in the wind turbine model (C_W, $\frac{C_W}{V_R - V_{CI}}$, D) and the siting configuration (ρ_f, ρ_e, d) can be selected to reduce WECS generation change can provide guidelines for siting wind turbine generators and model selection.

The values of D_R and D_C (and thus ΔL^+_k and ΔL^-_k) can not be reduced by wind turbine model or siting configuration selection if the farm penetration constraint is violated since the $N_F C_W = D_R = D_C$ and the farm penetration level does not necessarily depend on the wind turbine model and siting configuration but on the total capacity of wind turbines in an area swept out by a thunderstorm. The effective farm penetration can be reduced if the farm penetration constraint is violated by the controls discussed in section 5. These controls would reduce D_R and D_C and thus spinning reserve, unloadable generation and load following requirements if the farm penetration constraint were violated.

3. EFFECTS OF THE WTG MODEL

The analysis in the previous section showed that the change and rate of change of wind generation out of an echelon and farm are dependent on the following wind turbine model parameters; capacity C_W, the slope of the change of power produced with wind speed $\frac{C_W}{V_R - V_{CI}}$, and the distance D into the leading edge outflow where the wind speed first reaches rated velocity V_R for the WTG model. The capacity C_W and distance D are much larger for a MOD-2 WTG than for a MOD-1 while the slope $\frac{C_W}{V_R - V_{CI}}$ is nearly identical for the two WTG models. Thus, the change and rate of change of generation for an echelon (10,11) and farm (12) of MOD-2 WTGs will be much larger than for an identical echelon and farm of MOD-1 WTGs.

A detailed model and simulation of the MOD-2 and the MOD-2 wind farm was developed and is discussed in [3]. The discussion of the detailed operation of the MOD-2 is omitted here. The simulation of the coastal farm of MOD-2 wind turbines experiencing the Mitchell storm front is presented and compared with similar results for the MOD-1 presented in section 2. These simulation results on the MOD-2 confirm the results of the above analysis of the differences in power change and rate of change from the MOD-1 and MOD-2.

The power out of a coastal farm of MOD-2 wind turbines experiencing the Mitchell storm front is shown in Figure 2. Note that the power increases are

$$\frac{dP^+_e}{dt} = 1.75 \text{ MW/sec.}$$

which is larger than for the MOD-1 and that the period over which power changes on each echelon is T_M = 80s rather than 50s for the MOD-1. Thus the total power change, the rate of change, and the period over which the change in power on an echelon of MOD-2 WTGs is significantly larger than for an identical ehcelon of MOD-1 WTGs experiencing the same Mitchell storm front as predicted from the analysis.

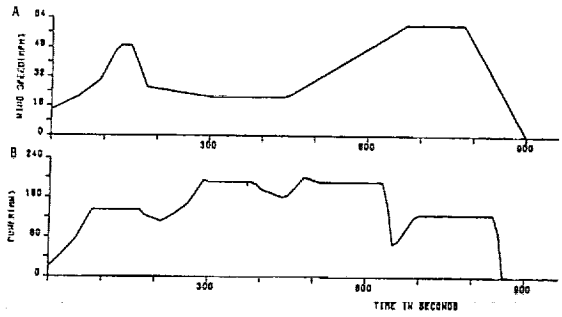

Figure 2 The Power Out of a Coastal Farm of MOD-2 Wind Turbines Experiencing The Mitchell Storm Front

The power output of the MOD-2 WTGs in the first echelon fall with the decrease in wind speed after passage of the very high winds of the leading edge outflow. The power output of a MOD-1 remains constant during this period because V_R = 18 mph is much lower on a MOD-1 causing the blade pitch controls to keep power output constant when wind speeds are above V_R.

The power increase out of the second echelon starts at T_e = 220s and is similar to that out of the first echelon. The power drop due to shutdown of the two echelons is quite rapid. The power decrease out of the first echelon is shown at t = 650 seconds followed almost immediately by a ramp increase in power on the second echelon due to increasing wind speeds for passage of the trailing edge inflow over this second echelon.

4. EFFECTS OF SITING CONFIGURATION ON WECS GENERATION CHANGE

The purpose of this section is to discuss how following factors affect the probable WECS generation change in ten minutes (Q^+_{Wk}, Q^-_{Wk}):

(1) density of WTGs in a farm ρ_f when $N_f C_W$ is held constant;

(2) uniformity of the farm siting configuration when $N_f C_W$ and ρ_f values are held constant;

(3) the wind speed characteristics of typical thunderstorms; and

(4) the correlation of wind speed characteristics at various sites in an echelon and farm.

This discussion will indicate how each of these factors affect probable changes in WECS generation for ten-minute intervals (Q^+_{Wk}, Q^-_{Wk}), and how one might attempt to minimize these probable changes and thus to minimize the changes in spinning reserve, unloadable generation, and load following capability required if the farm penetration constraint is satisfied. The siting configuration has no affect on the spinning reserve, unloadable generation, and load following requirements if the farm penetration constraint (18) is violated since the change in these requirements are embodied in changes in D_R and D_C to the farm capacity ($N_f C_W$) and not changes in Q^+_{Wk} and Q^-_{Wk}.

The effects of increasing ρ_f and not N_f or penetration $N_f C_W$ is indicated by simulating the WECS generation change out of a coastal farm of MOD-1 WTGs experiencing a Mitchell storm front when the distance between two echelons is decreased from 2 miles to 0.5 miles. The power change from this modified coastal farm, where the total number of WTGs is unchanged but the farm density is increased 2.5 times, is shown in Figure 3A. The average WECS power change as a function of the length of the interval over which the average is computed is plotted for the WECS generation change out of the modified coastal farm siting configuration in Figure 3B. Note that the average power system response rate capability curve is also included in Figure 3. The increased farm density has not increased the instantaneous rate of change in power from an array but held it at the level for 100s rather than 50s. The farm and echelon penetrations have to be reduced from 6% and 3%, respectively, to 4% and 2%, respectively, so that the average WECS generation change would not exceed power system response rate capability. If the density were increased as indicated, while holding the number of WTGs (N_f) and penetration ($N_f C_W$) constant, the peak frequency and area control error deviations would be larger and would not be reduced to low values as quickly because the system response and response rate capability are more severely stressed by the same total WECS generation change occuring in a shorter interval.

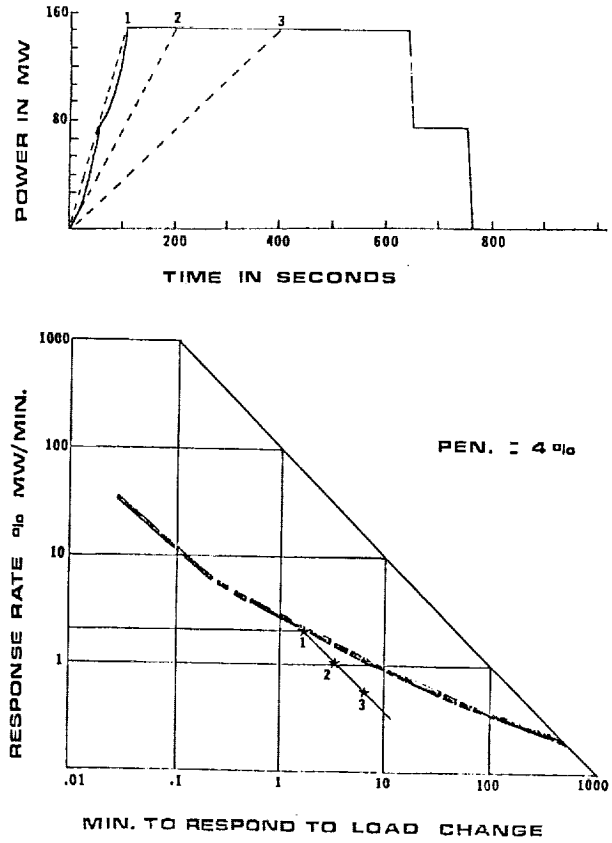

Figure 3 Power Change and Rate of Change from the Modified Coastal Farm of MOD-1 WTGs

The effects of reducing both farm and echelon siting densities without changing farm penetration is shown by simulating the WECS generation changes from the midwestern farm and coastal farms of MOD-1 WTGs as shown in Figures 4 and 5. The midwestern farm has the same 100 WTGs in 10 echelons of 10 WTGs each with separation between every WTG equal to 0.7 miles. The spreading out of generation, by reducing ρ_f and ρ_e and reducing ρ_e to values that more closely approach ρ_f

$$\rho_e = \begin{cases} 1.4\ \rho_f & \text{midwestern} \\ 4\ \rho_f & \text{coastal} \end{cases}$$

eliminates the saturation of area control error, reduces frequency and area control error deviations, and permits the utility to handle the WECS generation easily in a manner similar to load changes.

Thus, reducing farm and echelon density and maintaining echelon density at or near farm density levels (uniform low density farm siting patterns) could dramatically reduce WECS generation changes in ten minutes and the need to increase load following,

spinning reserve, and unloadable generation requirements. It should be noted wind speed characteristics, site availability, legal and environmental constraints seriously limit the ability to select uniform low density siting configurations. A coastal farm, where wind speeds drop as distance from the coast increases, is one example where higher non-uniform density configurations are likely.

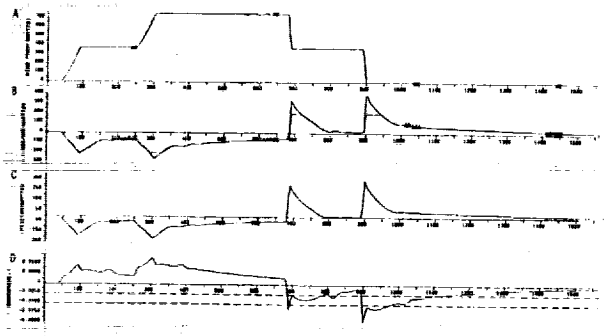

Figure 4 Effects of Power from a Coastal Farm on System Frequency and ACE

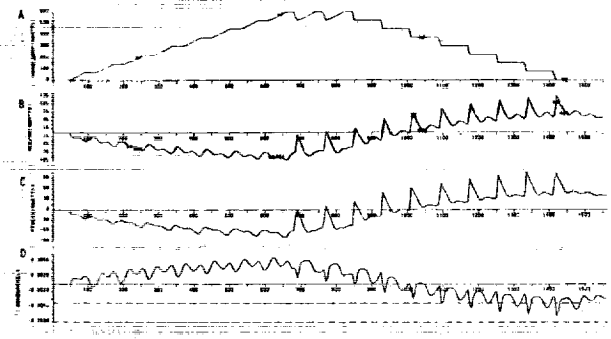

Figure 5 Effects of Power from a Midwestern Farm on System Frequency and ACE

The siting pattern assumed to this point is that all WTGs are sited in straight lines normal to the front although the definition of an echelon included all generation in strip D_o miles wide and D miles long in the direction of the motion of the storm front. The echelons were separated by a distance d which was greater than the MOD-1 or MOD-2 WTG value of D for the coastal and midwestern farm configurations. The effects of randomly siting WTGs in the farm maintaining a 0.5 mi. separation between WTGs, which avoids turbulence and loss of efficiency, was investigated for both coastal and midwestern farms. This random siting has the effect of making the density ρ_e of WTGs in every D x D_o area smaller and much closer to farm density levels. Thus, this random siting shows the effect of spreading out the siting within an echelon and the effects of reducing echelon density.

The coastal farm, with a d = 2.0 mile separation between echelons, was randomly sited by restricting all WTGs within the two mile strip but maintaining a 0.5 center band within this strip to satisfy the turbulence avoidance constraint. Note from Figures 1 and 6 for the original and randomly sited coastal farm, respectively, that randomly siting WTGs has smoothed out the power increases for passage of the thunderstorm leading edge outflow so that the rise is continuous with no intervals where WECS generation change has stopped. Random siting has made the drops in generation due to passage of the trailing edge inflow almost as smooth and continuous as the increases. This result indicates that the large almost instantaneous drops in generation, that could occur due to simultaneous loss of generation on an entire echelon, is not likely since the siting configuration is not likely to be perfectly straight lines normal to the motion of the thunderstorm front. The large frequency changes, which result due to the inability of frequency regulation to cope with such large instantaneous change, is also not likely.

The average response rate over a 70 second interval for this random sited coastal farm and the original farm are almost identical, as can be seen by comparing the power change on the two farms at t = 70s in Figures 6 and 1. This indicates random siting has virtually no effect on the average rate of change that must be coped for by frequency regulation and regulation in 60 seconds given by (10) for this Mitchell front. However, randomly siting the coastal farm would likely have greatly reduced the WECS generation changes for the O'Hare 6 wind speed profile, shown in Figure 7B, where adjacent echelons of the coastal farm had simultaneous increases. This random siting of echelons, which makes echelon densities smaller and more equal to farm density, could thus have decreased the changes in WECS generation out of the coastal farm. This result confirms that

(a) reducing echelon density and penetration, and

(b) making echelon density uniform by making it more nearly equal to farm density

decreases WECS generation change over ten minutes (Q^+_{Wk}, Q^-_{Wk}) as well as instantaneous rates of change which must be handled by frequency regulation and regulation controls.

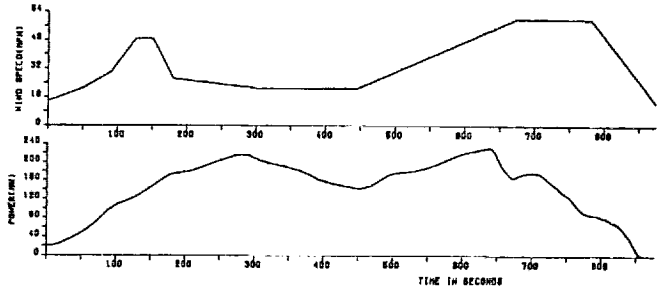

Figure 6 Random Sited Coastal Farm of MOD-2 WTGs with the Mitchell Storm Front

Wind speed time profiles during thunderstorms at Chicago's O'Hare International Airport and at Ludington, MI were measured and used at inputs to the original coastal farm siting configuration of MOD-2 WTGs, replacing the Mitchell storm front wind speed profile used exclusively up to this point. The power fluctuation out of this coastal farm for these various thunderstorm wind speed versus time profiles are given in Figures 7A-7D.

The actual measurements of wind speeds at these sites indicate there can be several peaks and lulls in a wind profile (Figures 7A-7C) and that the time interval between peaks can vary between 10 minutes to 40 minutes. The gradual buildup of wind speed for an advancing storm and the eventual peaks and lulls in the actual storm can be seen in Figure 7D.

The power from the coastal farm indicates that WECS generation changes can occur simultaneously on the two echelons which was not true for the Mitchell front. These WECS generation changes sometimes add giving short term (~ 1 minute) WECS generation change that is larger than can occur on a single echelon. This occurs at t = 300s and 1800s in Figure 7B where WECS generation changes reach 150 MW and 170 MW when the capacity of the echelon of MOD-2s is 120 MW. The repetition of these changes in wind speed and generation and the long duration of the thunderstorms (~ 1 hour) were not anticipated based on the Mitchell storm front data.

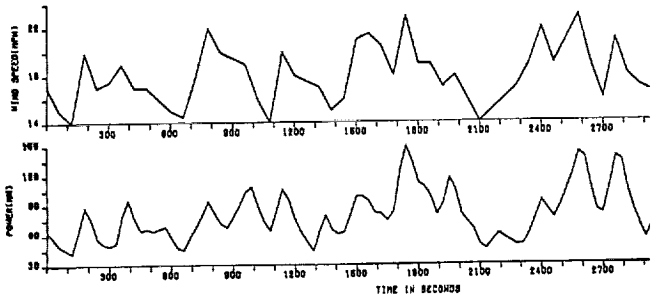

Figure 7A O'Hare 2 Storm Front on the Coastal Farm of MOD-2 WTGs

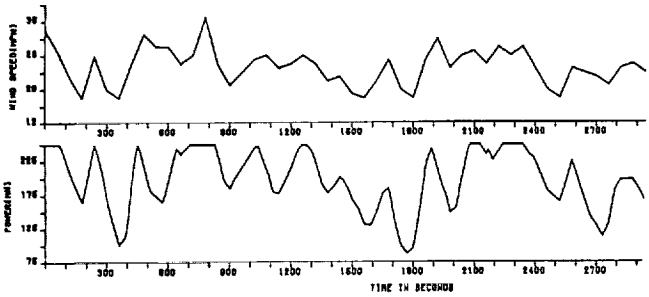

Figure 7B O'Hare 6 Storm Front on the Coastal Farm of MOD-2 WTGs

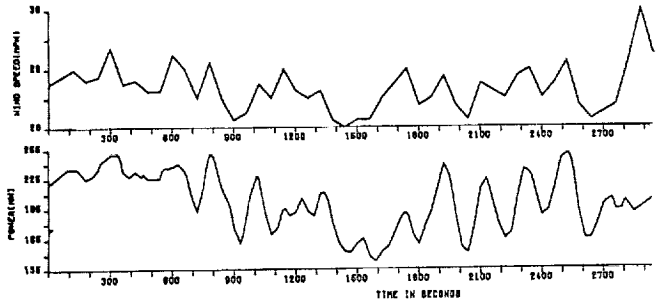

Figure 7C O'Hare 5 Storm Front on the Coastal Farm of MOD-2 WTGs

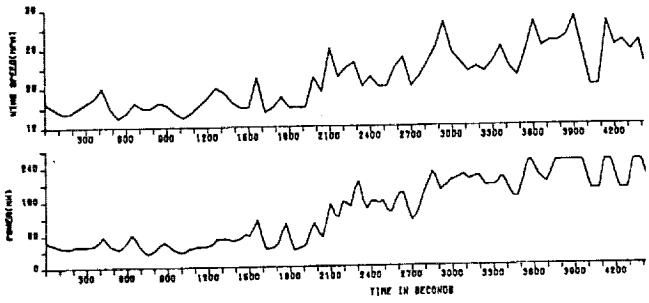

Figure 7D O'Hare 4 Storm Front on the Coastal Farm of MOD-2 WTGs

The effects of these large and cyclic power variations from the coastal farm of MOD-2s experiencing the O'Hare 6 wind speed versus time profile is shown in Figure 8. The simulation is performed on the 4000 MW system with 5% load following capability and experiencing ½%/min. load change for ten minutes in addition to these WECS generation changes on the 5.5% penetration coastal farm. The power variations from the coastal farm with O'Hare 6 wind speed profile is large and oscillatory. This is observed in large area control error and frequency deviations that reach peak to peak 150 MW and .03 hz respectively at t = 300s and approximately similar values at 1800s. The area control error saturated in both positive and negative directions within 100s in each case. Economic dispatch and economic dispatch/regulation units take on the load increase over the first 20 minutes and then respond to the overall cyclic (t = 800s) power changes in WECS generation, but not the faster changes seen on base and hydro units.

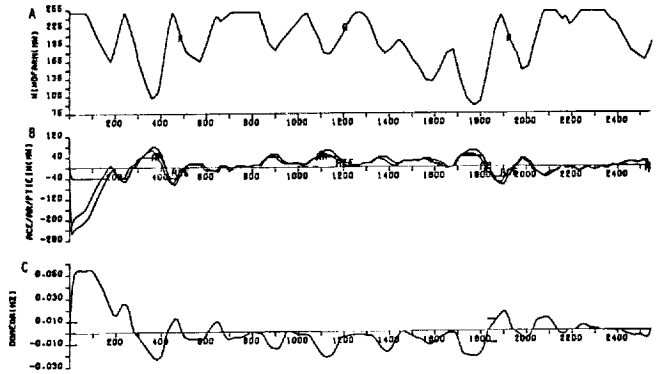

Figure 8 Effect of the O'Hare 6 Storm Induced WECS Generation Change on System Frequency and ACE

The large power changes from the coastal farm with O'Hare 6 wind speed profile are truly excessive for the 4000 MW system not only in size but also in terms of their repetition at t = 300, 1800 and 2700s and the duration of these changes (t = 3600). The size of these oscillations is due, in part, to the occasional overlapping of generation increases or decreases on different echelons. These large WECS generation changes can repeatedly cause saturation in area control error in both directions over a very short interval.

It would appear that reducing farm and echelon density without changing farm penetration would reduce the magnitude of these fluctuations. This is shown in Figure 9 where the O'Hara 6 wind speed profile is inserted into the midwestern farm configuration. Note that compared to coastal farm changes in WECS generation, shown in Figure 9b, the peaks and sharp valleys have been eliminated. The result indicates high echelon and farm density can have a major effect on the WECS generation changes over ten minutes as well as those over 60 seconds thus increasing spinning reserve, unloadable generation, and load following requirements as well as effecting the measures of operating reliability such as the average area control error and interval between area control error zero crossings.

It should be noted that the width of peaks and valleys, and duration between such peaks and valleys, probably are related to the very structure of a thunderstorm wind pattern. If statistics were determined on the width of peaks and valleys and duration between them, rules or principles for siting in coastal and midwestern farms could be developed that

would minimize WECS generation change out of an array. The analysis of wind speeds and the appropriate principles for siting WTGs is a subject for further research.

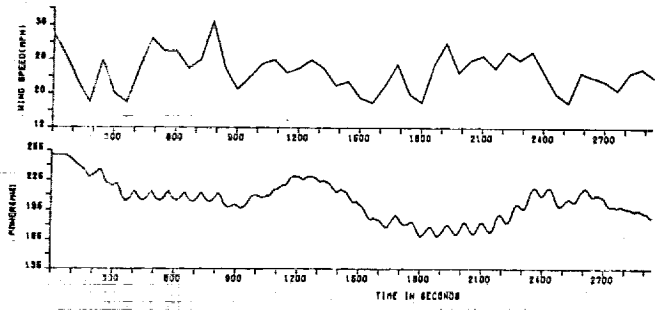

Figure 9 O'Hare Storm Front on the Midwestern Farm of MOD-2 WTGs

The analysis and simulation of thunderstorm induced WECS generation changes have assumed that the wind speed at every point along a straight line normal to the direction of front motion is identical and perfectly correlated and that the wind speed profile propagates at V_o so that each WTG observes the same wind speed profile. This may not be true in reality and thus an effort is made to assess what effect the assumption of perfect correlation of wind speed in an echelon and the assumption that the wind speed profile propagates from echelon to echelon unchanged has on the size of power variations from a farm. The present correlated echelon wind farm model works as follows.

The power out of a single WTG is multiplied by the number of WTGs in an echelon and then this echelon power output is delayed by $\frac{nd\ 3600}{V_o}$ to get the output of the nth echelon. The output of all echelons is then summed. This wind farm model assumed all wind speeds in an echelon are perfectly correlated and that the wind speed profile propagates from echelon to echelon. A second wind farm model assumes power out of each WTG is independent. If power out of each WTG is assumed to be a gaussian process, then if all wind turbines in a farm see independent identical stationary ergodic wind speed processes, a sample function of the power out of such a farm is

$$P_f(t) = N_f m_X + \sqrt{N_f}\left(P_W(t) - m_X\right) \qquad (19)$$

where $m_X = \frac{1}{t}\int_o^t P_W(t)dt$ and $P_W(t)$ is a sample function of the power out of a single WTG for this wind speed process. A perfectly correlated model of power out of a farm assumed the wind speed process at every WTG are an identical stationary ergodic gaussian processes which are perfectly correlated so that

$$P_f(t) = N_f P_W(t) \qquad (20)$$

The output of independent model, perfectly correlated model, and the perfectly correlated echelon wind farm model are shown for wind speed profiles measured during thunderstorms at O'Hare 5 and 6 in Figures 10 A-C, respectively and 11 A-C, respectively. Note that power variations out of the perfectly correlated model, perfectly correlated echelon model, and independent model are generally successively smaller. There are exceptions when the perfectly correlated echelon model has larger power variations than the perfectly correlated model, which occurs when power increases on different echelons simultaneously.

The assumptions concerning the correlation of wind speeds at various sites thus not only affect the magnitude of the variations over a one minute interval but also the variations over a ten minute interval. Thus, the correlation of wind speeds can significantly affect the statistics of the changes in WECS generation out of an array over a ten minute interval and thus the selection of (Q^+_{Wk}, Q^-_{Wk}) in the load following, spinning reserve, and unloadable generation requirements.

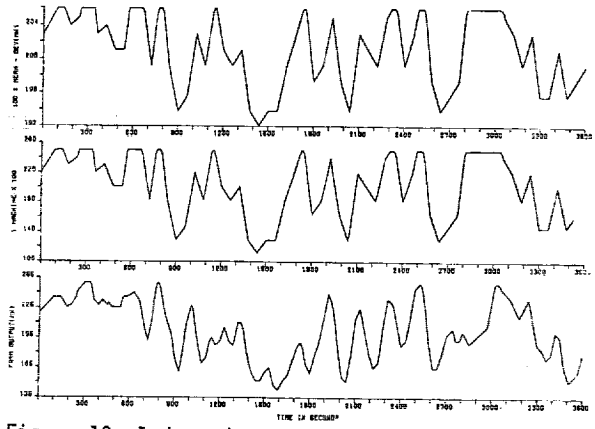

Figure 10 Independent, Correlated Farm, and Correlated Echelon Wind Speeds on WECS Generation from the Coastal Farm with O'Hare 5 Wind Speed Profile

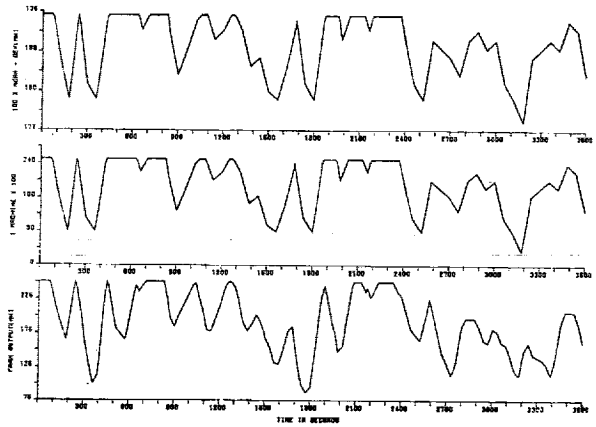

Figure 11 Independent, Correlated Farm, and Correlated Echelon Wind Speeds on WECS Generation from the Coastal Farm with O'Hare 6 Wind Speed Data

5. EFFECT OF WIND ARRAY CONTROLS

The previous two sections discussed factors, which depend on the WTG model (C_W, D. $\frac{C_W}{V_R - V_{CI}}$) and siting configuration (ρ_f, ρ_e, d), that affect probable WECS generation change (Q^+_{Wk}, Q^-_{Wk}). The selection of wind turbine models and siting configuration are often based on economics, wind conditions, site availabiltiy and other factors which do not permit the most favorable WTG selection and siting configuration combination. Moreover as WECS generation penetration increases no WTG model and siting configuration will reduce the probable changes (Q^+_{Wk}, Q^-_{Wk}) in WECS generation sufficiently to eliminate the need for increased spinning reserve, unloadable generation and load following requirements and the

appropriate modification of regulation and economic dispatch controls as described in [3]. Finally, WTG model and siting configuration selection only have effect on reducing the need for modifying unit commitment, regulation, and economic dispatch if the farm penetration constraint is satisfied.

The direct controls of WECS generation change, discussed in this section, can:

(1) reduce the effective farm penetration when thunderstorms are present and thereby make an array that would otherwise violate the farm penetration constraint effectively satisfy the constraint. This satisfaction of the farm penetration constraint thus makes the increase in spinning reserve, unloadable generation, and load following requirement depend on the probable change in WECS generation in ten minutes Q^{+}_{Wk} and Q^{-}_{Wk} and not on the modification of D_R and D_C to $N_F C_W$;

(2) significantly reduce the probable WECS generation changes in ten minutes (Q^{+}_{Wk}, Q^{-}_{Wk}) assuming that WTG model and siting configuration have been appropriately selected and that the effective penetration of the array with these controls present satisfies the farm penetration constraint.

Two direct controls limit the WECS generation change out of an array during any ten minute interval by coordinated control of blade pitch angles of all WTGs in an array. These controls would also reduce the apparent farm penetration during thunderstorms so that it meets the farm penetration constraint. One of these controls would clip WECS generation change in any ten minute interval and the other causes partial shutdown of each echelon in anticipation of the storm so that the effective farm penetration satisfies the farm penetration constraint and the WECS generation changes are capable of being handled by the unit commitment, regulation, and economic dispatch controls that are set when WECS generation is not present.

The partial shutdown of each echelon reduces both the ramp WECS generation increases and the sudden WECS generation drops on each echelon by 50%. The area control error, frequency, and tie line power deviations for each of these changes is thus decreased by approximately 50% also.

Frequency regulation is seen to be more capable of quickly reducing frequency deviations after the sudden drops of WECS generation on each echelon because they are smaller. Finally the saturation of area control error after the drop in WECS generation on the second echelon is reduced from 500s to 100s indicating the effectiveness of a partial shutdown in anticipation of the arrival of a thunderstorm front.

This partial shutdown would require wind speed monitors to detect the approach of a thunderstorm from any direction. Both clipping and partial shutdown would result in lost energy and that may somewhat reduce the economic attractiveness of the wind turbine arrays.

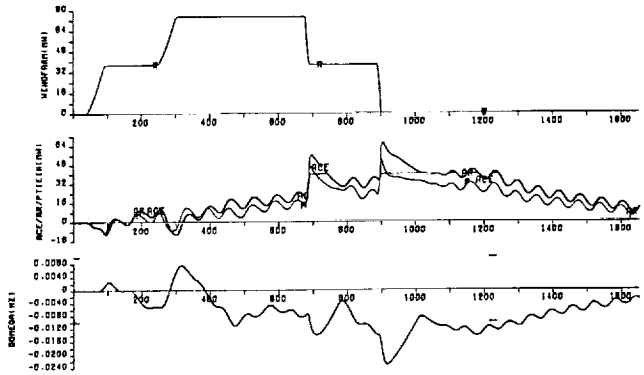

Figure 12 Effect of Partial Shutdown on ACE and Frequency Deviation

6. CONCLUSIONS

The paper discusses methods of reducing the wind generation changes from an array for passage of a thunderstorm by wind turbine model selection and site configuration selection. Coordinated blade pitch controls are also discussed and can be used to reduce the effective farm penetration level so that the farm penetration constraint is not violated. Satisfaction of this constraint implies that the added spinning reserve unloadable generation and load following requirement on unit commitment and the added response capability of AGC controls depends on WTG model selection and site configuration selection and not on the capacity of the farm. These coordinated blade pitch controls on each WTG in the array could also reduce the wind generation change out of an array much as wind turbine model and site configuration selection. The wind generation change after appropriate wind turbine model selection, site configuration selection, and coordinated blade pitch controls must be responded to by the units under AGC control. Limitation on site availability and wind turbine model selection and economic incentives for higher density siting may contribute to a rather significant change and rate of change in WECS generation especially during severe weather conditions. The adjustment of unit commitment to allow sufficient spinning reserve, unloadable generation, and load following capability and the adjustment of AGC controls to exploit the response capability available from unit commitment are discussed in [3].

7. REFERENCES

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[2] Schlueter, R.A., Park, G.L., Modir, H., Dorsey, J., and Lotfalian, M., "Analysis and Simulation of Storm Induced WECS Generation Changes on System Operation," IEEE Winter Power Meeting, Paper WM-81-171-8, and accepted for IEEE Trans. on Power Apparatus and Systems.

[3] Schlueter, R.A., Park G.L., Lotfalian, M., Dorsey, J., and Shayanfar, H., "Operations Model for Utilities Using Wind Generator Arrays," Final report to U.S. Department of Energy Under Contract COO-23168-80/1, November 1980.

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